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OF COUNSEL
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August 26, 1983

FEDERAL EXPRESS

Mr. Ronald Nelson
Department of Water and Power
Room 932
111 North Hope Street
Los Angeles, California 90051

Dear Ron:

Enclosed please find the final draft of the Engineering Review-Summary for the IPP generating station. You will note that the recommendation as to NOx has been changed from the draft to reflect the language in the notice published in the newspaper.

If you have any questions, please let me know.

Very truly yours,

James A. Holtkamp

JAH:bb
Enclosure

cc: Mr. Ronald L. Rencher
Mr. James H. Anthony
Mr. Roger T. Pelote
Mr. Lowell L. Smith
Henry V. Nickel, Esq.
Andrea Bear, Esq.
H. Michael Keller, Esq.

Major
Appoval
ID# ____________________

BUREAU OF AIR QUALITY
ENGINEERING REVIEW - SUMMARY (NOI Dated 4-13-83)
ENGINEER/DATE Dave Kopta/John Walton/8-26-83

Owner/Operator: Intermountain Power Association

Source: Intermountain Generating Station

Applicant/Official: James Anthony

Applicant/Official Address: P.O. Box 111, Room 931, L.A. CA 90051

Telephone Number of Contact:

Plant/Activity Location and Address: Delta, Utah

Type of Operation: Coal Fired Boiler, Utility Electric Steam Generator

I. Background

August 2, 1978, Intermountain Power Project (IPP) submitted to this office a notice of intent to construct electric generators located near Lynndyl. August 9, 1978, Al Rickers asked IPP to submit plans and specifications for the actual air pollution control devices to be used on the project and operating specifications for the boilers.

September 25, 1978, IPP notified this office that detailed plans and specifications were not available at that time because the project was still in the planning stages. IPP asked for concept approval in accordance with Section 1.6.5, Utah Air Conservation Regulations (UACR). IPP asked for the permit based on the information submitted for the Salt Wash Site, stating that information would apply to the Lynndyl site as well. Also, in that letter is the following statement concerning the detailed plans for the project, "As these details are completed, they will be submitted to your office for your approval."

On August 1, 1980, the plan review based on the preliminary plans was completed. That review calculated emissions based on the following:

1. Four 750 mw boilers with heat input of 7.493 X 10^9 BTU per boiler

2. Particulate control of 99.5% by hot side E.S.P.

3. 50% additional particulate control from the FGD.

4. SO_2 removal of 90% by horizontal spray chamber lime slurry scrubber.

5. NO_x emissions of .6 lb/10^6 BTU heat input. (EPA required .55 lb/10^6 BTU)

6. Emission rate calculations were as follows:

Particulate	1,950 tons/year + fugitives
SO_2	4,321 tons/year
NO_2	66,951 tons/year

December 3, 1980, this office issued an approval order for the project based on the August 1, 1980, plan review. The approval order has the following conditions:

1. All pollution control procedures and facilities shall be adopted or installed as proposed.

2. SO_2 emission rate .155 lbs/10^6 BTU averaged over 30 days.

3. SO_2 removal of at least 90%.

4. NO_x emission rate .60 lbs/10^6 BTU averaged over 30 days.

5. Particulate emission rate of .02 lbs/10^6 BTU.

6. Opacity 20% except for one 6 minute period of 27%, in any hour.

October 22, 1981, IPP submitted to this office the final design for the boilers.

March 11, 1982, IPP submitted to this office the final design for the SO_2 scrubber and the particulate control.

August 23, 1982, I was assigned and began review of the final plans.

The following changes to the design upon which the approval order was based were found in the review of the final plans.

1. Boiler rated capacity increased from 7.493 X 10^9 BTU/hr to 8.352 X 10^9 BTU/hr.

2. The SO_2 scrubber was changed from a lime slurry, horizontal spray chamber with five modules, to a limestone slurry, vertical spray tower with six modules.

3. Particulate control was changed from a hot side ESP to a baghouse.

September 3, 1982, this office sent a letter to IPP informing IPP that the change in boiler size required a modified approval order. IPP was also informed that all of the procedural steps required to obtain a new approval order would be required to obtain a modified approval order. Additional information regarding the baghouse and SO_2 scrubber were also requested in that letter.

April 13, 1983, IPP submitted by letter a response to the September 3, 1982, letter answering the question regarding the SO_2 scrubber and baghouse. The letter also informed this office that the project had been downsized from four to two units, and in IPP's opinion, a BACT review was not required. This office did not agree with IPP's opinion, and the April 13, 1983, letter was considered by this office to be a notice of intent (to modify). The following plan review is based on the information in that letter and the contract documents submitted on October 22, 1981, and March 11, 1982.

II. Proposal

A. IPP plans to install two Babcock and Wilcox coal fired boilers. According to the contract #2010N effective date May 29, 1981, which IPP submitted as detailed plans, the boilers will have the following capacities:

Maximum capacity
Steam at superheater outlet = 6,100,000 lbs/hr at
1,005^{o}F and 2,515 psig.
Steam at reheater inlet = 5,500,000 lbs/hr at
620^{o}F and 539 psig.
Maximum continuous rating
Superheater outlet 6,600,000 lbs/hr at
1,005^{o}F and 2,640 psig.
Reheat inlet 5,500,000 lbs/hr at
1,005^{o}F and 630 psig.
Burner level heat release rate = 1.6 X 10^6 BTU/hr/ft^2
based on coal B.

The terms maximum capacity and maximum continuous rating do not have the meaning they appear to have. They are levels of operation at which certain contract guarantees apply. The maximum continuous rating steam flow of 6.6 X 10^6 lbs/hr equates to a boiler heat input of 8.040 X 10^9 BTU/hr. based on B coal

Roger Pilote submitted to me by phone the boiled dimensions (85 feet wide by 60 feet deep or 5,100 square feet). With the burner heat release rate of 1.6 X 10^6 BTU/hr/ft^2, the boiler heat input calculates to 8.16 X 10^9 BTU/hr.

Both are lower than the 8.352×10^9 BTU/hr heat input cited in the fabric filter and SO_2 scrubber contracts. IPP has asked to be permitted to the 8.352×10^9 BTU/hr level so that if the boiler exceeds its rated capacity, IPP could operate at the higher rate limited by the baghouse and SO_2 scrubber design.

This review is based on boiler heat input of 8.352×10^9 BTU/hr. This equates to 961 gross MW produced by each boiler and 855 MW net after plant power consumption.

The boilers will use Babcock and Wilcox dual register burners. The burners will be placed on opposing walls of the furnace (front and back wall) a total of 48 burners will fire the coal. On each of the two walls, the burners will be arranged in a matrix four rows high by six burners per row. There will be 15 feet between rows and 10 1/2 feet between burners on a row. A diagram of the cross-section of the dual register burner is included in this review.

Each row of burners has its own coal pulverizer and feeder, for a total of eight pulverizers. Each row of burners also has its own combustion air supply which can be controlled independently of the other rows.

Burner capacity is cited at 115% of boiler maximum capacity, such that the maximum capacity rating can be maintained with one pulverizer out of action and remaining pulverizers in worn conditions.

115% of maximum capacity is 8.491×10^9 BTU/hr which is above the heat input requested in the NOI.

At maximum continuous rating, theoretical combustion air is cited as 6.047×10^9 lbs/hr and actual air required is 6.954×10^9 lbs/hr. This is 15% excess air. (From original Contract)

Boiler fuel efficiency is cited as 88.54%. Other boiler details are attached.

B. Particulate

For particulate control, IPP proposes to install two general electric (formerly Buell) fabric filters (one per boiler). The following design features will be incorporated in each of the baghouses.

1. The baghouse will be located downstream of the air preheaters and upstream of the I.D. fans and SO_2 scrubber. Therefore, the baghouse will be under negative pressure.

2. The baghouse is designed to handle the flow from a boiler operating at 8.352 X 10^9 BTU/hr peak load, but calculations are based on maximum continuous rating.

3. At maximum continuous rating, gas flow will be 3.750 X 10^6 ACFM at 285°F and 24.33 inches Hg absolute.

4. Filtration area:
   a. 1.97 X $10^6 ft^2$ per baghouse
   b. Three units per baghouse
   c. 16 compartments per unit
   d. 420 bags per compartment

5. Filtration velocity (air to cloth ratio):
   a. with all compartments on line, 1.9 ft. per minute
   b. with one compartment cleaning and one down for maintenance per unit, 2.17 ft. per minute.

6. Bag cleaning will be by reverse air at a rate of two feet per minute. Reinflating of bags will be gentle rather than a snap action. Reinflation fans will have an installed spare.

7. Filter material will be fiberglass with the following properties:
   a. Fabric weight: 13.5 $\pm$ .7 ounces/$yard^2$
   b. Count: F44 X T24 two textured one filament
   c. Weave: 3 X 1 twill
   d. Permeability: 45-60 ft^3/minutes/$feet^2$ at .5 inches H_2O
   e. Yarn nomenclature:
      ECD glass, warp 37-1/0
      fill - 75-1/3
      (2:75 - 1/0 Tex 1.75 - 1/0 Fil.)
   f. Bag finish: acid resistent minimum finish 4% in 30 minutes at 1150°F
   g. All fibers encapsulated with Globe Albany's Q78-877 or Burlington I625

8. Pressure drop across the bags will be 6.0 in H_2O.

9. Ash hoppers will have 12 hours of storage capacity, will be heated, and will have a slope of 55°.

C. SO_2 Scrubber

IPP proposes to install two G.E. (formerly Chemico) scrubbers. Proposed are spray tower type limestone scrubbers. Each scrubber will have six independent absorber modules, four of which can handle the total flow (at maximum continuous rating) of gas from one of the IPP boilers. This gives two spare modules per boiler to allow for downtime and mechanical failures. Design features for each unit are as follows:

At maximum continuous rating:

1. Gas flow:
   a. 10.453×10^6 lbs/hr
   b. 2.3×10^6 DSCFM
   c. 3.9×10^6 ACFM

2. Gas temperature:
   a. 285°F at inlet
   b. 145°F at outlet

3. SO_2 flow rate at inlet - 12,530 lbs/hr

4. Liquid to gas ratio - 60 gpm/1000 acfm

5. Limestone required - 21,370 lbs/hr

6. Stoichiometric ratio - 1.08

7. SO_2 removal - 90%
   SO_3 removal - 70%
   SO_2 in exit gas - 1253 lbs/hr

8. Water droplet carry-over 885 lbs/hr

9. Gas velocity in scrubber - 9.8 ft/sec

10. Liquid recirculation rate - 46,800 gpm

11. pH - 5.5 to 6.0

12. Slurry solids 10% by weight

13. Blow down - 546 gpm

14. Solids discharge rate - 30,042 lbs/hr

15. Make-up water source, cooling tower blow down applied to mist eliminator

16. Gas flow area:
    a. absorber - 1320.0 $feet^2$
    b. mist eliminator - 1230 $feet^2$

17. 14 nozzles per header
12 headers per stage
3 stages per module
4 modules per boiler at MCR

18. Spray nozzle type - Spraco ramp bottom hollow cone or equal - can pass a 1 1/4 inch particle

19. Header pressure - 11 psi

20. Flow - 93 gpm per nozzle

21. Distance between headers - 72"
Distance between nozzles - 27"

The scrubber will be downstream of the I.D. fan and will be the last system prior to the stack. The scrubber will operate under positive pressure. The scrubbers are designed to operate with a flyash loading of 0.02 lbs/10^6 BTU at the inlet, and the mist eliminators are designed to keep outlet particulate below 0.02 lbs/10^6 BTU. No additional particulate control above that obtained by the baghouse is designed for the SO_2 scrubber. The ductwork is such that in the event of baghouse bypass, the SO_2 scrubber will remain on line and remove some of the particulate.

Limestone slurry preparation will be done on site with three ballmills, i.e., one ballmill per scrubber, and one spare. Each ballmill can handle 30 tons per hour of limestone. Limestone will be ground to 90% passing a 200 mesh sieve. Slurry storage capacity of 24 hours will be available.

II. BACT Analysis

A. Particulate

To establish an appropriate emission level for particulate BACT, I surveyed the EPA BACT cleaning house. I looked for large utility boilers permitted since 1980. I found 24 plants permitted and, of those, 22 were permitted at the NSPS limit of 0.03 lbs/10^6 BTU, one plant (Nevada Power) was permitted at 0.015 lb/10^6BTU and, for one plant, I could not find the emission limit.

The California Air Resource Board has recommended a limit of 0.005 gr/acf for new coal fired utility boilers in California. That limit equates to approximately 0.015 lb/10^6 BTU.

IPP's baghouses are designed to meet a limit of 0.02 lbs/10^6 BTU. Based on the above survey, I recommend that 0.015 lb/10^6 be considered LAER and 0.02 lbs/10^6 BTU be considered BACT.

The following is a review of the designed details of the baghouse. Design criteria to meet a specific emission limit for a baghouse is not quantifiable by equations. Design is done largely by experience. All of the below design criteria fall in the range of current design practice. I have no reason to suspect that this baghouse will not meet 0.02 gr/dscf.

1. Bag cleaning will be by reverse air at a rate of two feet per minute. Reinflation of the bags will be gentle rather than snap action. Reverse air cleaning is the most condusive to long bag life of the commonly used cleaning systems. Gentle reinflation is also condusive to long bag life. Reinflation fans will have an installed spare. This feature will reduce downtime due to mechanical failures.

2. Filter material - Reverse air cleaning allows the use of fiberglass bags which have good heat resistance properties at low cost but poor resistance to cleaning abrasion. IPP will use fiberglass bags with acid resistant coating. Acid resistant woven fiberglass bags are commonly used for coal fired boiler applications. Glass bags can handle temperature surges up to 550^{o}F. Acid resistant coating on the fibers will protect against attack from H_2SO_4, SO_2, and fluorides.

3. Filtration velocity is one of the more important criteria with regards to dust removal efficiency. The lower the filtration velocity, the lower emissions should be. IPP's design calls for 2.17 ft/min. One to four ft/min is acceptable for reverse air system baghouses. Two ft/min is quite common for coal fired boilers.

4. Pressure drop - IPP will have 6 inches H_2O pressure drop across the bags. Pressure drop effects the cost of operating the fans for the boiler. Pressure drops of 1 inch to 10 inches are common design.

5. Ash hoppers - Hoppers will have a slope of 55^{o}, will be heated, and have storage capacity of 12 hours. This is an adequate slope to prevent hangups, heaters will prevent freeze-ups, and 12 hour storage will allow minor maintenance with no downtime.

B. <u>SO_2 BACT</u>

A review of the EPA BACT clearing house shows that of the 24 utility boilers permitted since 1980, two have been at 95% control of SO_2, four at 90% control, and the rest at lesser percent removal efficiencies. In terms of emission rate; one plant has been permitted at 0.1 $lb/10^6$ BTU, one at 0.12, and one at 0.13 $lbs/10^6$ BTU, two plants at 0.20 $lbs/10^6$. The rest vary from 0.36 to 01.2 $lbs/10^6$ with most between 0.4 and 0.6 $lbs/10^6$ BTU.

The sulfur content of the fuel effects the relationship between removal efficiency and BACT. The lower the coal sulfur content, the less expensive it is to achieve higher removal efficiencies. This is due to the need for less limestone to react with less sulfur and a smaller slurry flow system to deliver the lesser amount of limestone when dealing with low sulfur coal.

IPP's scrubber is designed to remove 90% of the SO_2 when burning coal with .84% sulfur. I recommend that we consider 90% removal as BACT for this plant. IPP has contracted to buy six coals for the project with the following sulfur and heat contents:

	%S	BTU/lb
A	0.75	10,930
B	0.55	11,010
C	0.48	11,577
D	0.59	11,690
E	0.44	11,060
F	0.93	9,662

It is specified in the contracts that coal F will be blended with another coal to a 50%/50% mixture. This would result in a coal with 0.84% sulfur and 10,296 BTU/lb if coal A is the other coal. After 90% removal of SO_2, this coal would emit 0.16 $lb/10^6$ BTU. Coal A alone would emit 0.14 $lb/10^6$ BTU after 90% removal. This is the next to worse case coal. I recommend that coal blending to achieve 0.15 $lbs/10^6$ BTU at 90% control be considered BACT.

Specific design features with respect to BACT:

The major design features of this system all attempt to maximize the amount of time that the scrubber will be online. The most outstanding feature of the scrubber along that line is two spare modules. Each scrubber will have six modules, four of which will be capable of handling the total gas flow at maximum continuous rating. This allows for one module to be under maintenance, and one to be on standby ready to replace any online module if a mechanical failure occurs. Two spare modules almost assures no loss in efficiency due to breakdowns.

The spray tower design is generally considered less efficient than other designs, which give more retention time and/or more surface area for liquid gas contact. But the spray tower design is less susceptable to scaling and plugging than the more efficient designs.

The spray nozzles are sized to allow a 1 1/4" particle to pass through. This will allow for large scale particles to circulate without plugging the nozzles. Large nozzle openings in conjunction with a low spray pressure (IPP proposes 11 psig) are not conducive to fine atomization of the spray drops. Fine atomization creates more liquid/gas surface area; therefore, more rapid absorption of SO_2. This feature is again sacrificing peak scrubber efficiency for reliability.

DK:wml
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C. NOx BACT

1) General

NSPS for NOx was defined in 1979 as 0.6 $lbs/10^6$ BTU for bituminous coal and 0.5 $lbs/10^6$ BTU for subbituminous coal. IPP will burn predominantly low sulfur bituminous coal. At the state level we have found 2 states with a NOx policy. New Mexico has a law requiring control of NOx to 0.45 $lbs/10^6$ BTU or less and the California Air Resources Board (CARB) has come out with guidelines requiring Selective Catalytic Reduction for control of NOx to 0.09 $lbs/10^6$ BTU on all new coal fired power plants.

According to New Mexico state officials, the 0.45 $lbs/10^6$ BTU standard was not based on a rigorous technical evaluation of available NOx control strategies. The proposed CARB guidelines were established after extensive staff research and are supported with a guideline document. The guidelines require NOx control to 0.45 $lbs/10^6$ BTU with combustion modification combined with SCR at 80% control to give a 0.09 $lbs/10^6$ BTU limitation.

A review of the EPA BACT clearinghouse shows that of the boilers permitted since 1980, 12 have been at 0.60 $lbs/10^6$ BTU, 2 at 0.55 $lbs/10^6$ BTU, 8 at 0.5 $lbs/10^6$ BTU, and 3 at 0.45 $lbs/10^6$ BTU. The listing does not specify the type of coal burned. In addition the staff has learned of 2 sources presently in the permitting process. Southern California Edison has proposed a NOx limitation of 0.45 $lbs/10^6$ BTU and Shell has proposed a limitation of 0.21 $lbs/10^6$ BTU at its Belridge Plant in Kern County, California. All the boilers including the Shell Belridge plant will be controlled with combustion modification techniques. The Shell plant will use the Exxon Thermal DeNOx process as a backup in case they have problems meeting 0.21 $lbs/10^6$ BTU with combustion control.

Recent permits in the Intermountain West have been at 0.45 $lbs/10^6$ BTU for subbituminous coal and 0.55 $lbs/10^6$ BTU for bituminous coal.

2) Combustion Modification

The present state of the art in commercially available boilers was assessed through conversations with the major U.S. boiler manufacturers. In each case company engineers were asked about the expected performance of their units burning Central Utah Coal. Foster Wheeler reported tests on bituminous coal in the range of 0.2 to 0.3 $lbs/10^6$ BTU. They are currently bidding on the Shell Belridge Plant which contains a Utah bituminous as one of its guarantee coals. Combustion engineering maintains that they can accommodate any NOx regulation their customers must meet with performance being a function of cost. Their Low NOx Concentric Firing System could meet a 0.40 $lbs/10^6$ limitation with Utah Coal. Anything below that would get expensive.

In order to determine the expected performance of the B & W burners with bituminous coal, we obtained reports of test results from existing plants with similar configurations. The first report is titled "Long Term Optimum Performance/Corrosion Tests of Combustion Modifications for Utility Boilers, Louisville Gas & Electric Co., Millcreek #3" by Exxon Engineering. Methods of decreasing-NOx emissions were tested from an environmental and corrosion point of view. Adjustment of excess air and biased firing of the burners within a limited range reduced baseline emissions of 0.55 $lbs/10^6$ BTU to between 0.44 and 0.50 $lbs/10^6$ BTU without adverse affects such as increased corrosion or slagging.

It was felt that further adjustment, unavailable here due to control room adjustment limitations, would yield lower emission rates without adverse side affects.

Figures 1 & 2 illustrate the data from the low NOx operational adjustments at Millcreek #3. Figure 1 demonstrates that the unit consistently operated below 0.50 lbs/10^6 BTU at low loads throughout the testing. Figure 2 illustrates the affect of excess oxygen on NOx emissions at full load. This correlation was obtained irrespective of other boiler parameters and clearly demonstrates the importance of excess oxygen on NOx emissions. The regression equation predicts that operation at 3.2% excess oxygen would achieve compliance with a 0.50 lbs/10^6 BTU NOx limitation under full load conditions.

The second report "Characterization of the NOx & SOx Control Performances; Southern Indiana Gas & Electric, A B. Brown Unit #1" by GCA Corporation reported baseline emissions of less than 0.5 lbs/10^6 BTU and results during testing of 0.370 to 0.388 lbs/10^6 BTU. The emissions were well below 0.50 lbs/10^6 BTU even at full load. IPP has pointed out that the A.B. Brown Unit contains furnace division walls which lower the overall heat release rate and therefore the NOx emissions. Utah coals would preclude the use of this feature at IPP. IPP also commented that the failure of the NOx monitor to meet EPA specifications means that the 0.39 lbs/10^6 BTU could be as high as 0.51. This statement is technically incorrect. In order to extrapolate from an approximately 8 hour certification test to a 30-day rolling average one must calculate the standard error of the instrument readings rather than the standard deviation. Random errors tend to average out with large sample sizes.

Other studies report that emissions of 0.38 lbs/10^6 BTU have been achieved at Southern Electric Generating Company, E. C. Gaston #1 (bituminous) and the Public Service Company of Colorado, Comanche #2 (subbituminous). This represents a decrease in NOx emissions of 29% and 62% respectively from typical operating conditions.

All existing units implementing B & W horizontally opposed dual register burners for which we have data appear to be able to meet a 0.50 lbs/10^6 BTU standard. All of them except one appear capable of meeting 0.45 lbs/10^6 BTU. New units which can meet a 0.40 lbs/10^6 BTU standard are available from at least two manufacturers. The only other plant presently in the permitting process which is proposing to burn Utah Bituminous Coals, the Shell Belridge Plant, is proposing a 0.21 lbs/10^6 BTU limitation which will be met through combustion controls.

3) Exxon Thermal DeNOx

The staff was unable to find an example of the use of this process on a full scale coal fired power plant although it is commonly used on oil & gas units. The process is capable of 50% NOx control on oil & gas units and testing indicates that similar control could be achieved with coal. Shell has proposed DeNOx technology as a backup at its Belridge Plant in an "offset" situation. The project has not been reviewed for BACT. Estimated costs for Thermal DeNOx control are given below.

4) Selective Catalytic Reduction

SCR is being routinely required on new coal fired power plants in Japan, but has only been demonstrated at the pilot plant stage in the U.S. Pilot plant testing in the U.S. suggested that eastern U.S. coals may cause catalyst plugging problems unseen in Japan. Whether western coals, which are more similar to the Australian and South African coals burned in Japan will cause similiar problems is uncertain. There is a great need, but apparently no EPA money, for a prototype scale test on a 10-100 MW facility in the U.S. to demonstrate and work the bugs out of the technology. Given the rapidly increasing experience of the Japanese with SCR, a demonstration plant may eventually become unnecessary.

5) Costs

IPP is in a unique situation with respect to costs in that it can be considered neither a completely new nor an existing source. The staff does not believe all the project delay costs calculated by IPP should be considered since the unapproved project modifications and failure to promptly submit an NOI are the responsibility of IPP. On the other hand, some excess costs would have been incurred even with prompt action by IPP.

As a compromise, costs for retrofit after one year of operation are used. The estimated cost for an 80% removal SCR system installed-one year after initial plant operation is 893 million 1983 dollars. This includes increased capital costs for the project and capitalized operation costs. The cost for installation of the SCR unit would be about 5.8% of project capital costs. A comparison of NOx versus SO_2 removal costs is:

Pollutant	\$/kw	\$/lb removed	\$/lb-eq acid
Low NOx Burn.	1.08	.03	1.16
NOx (Exxon)	11.3	.19	8.58
NOx SCR	25.8	.33	15.37
Retrofit SCR	32.2	.42	19.20
SO_2	48.2	.41	13.12

Recomendations

Based on the above table, SCR might be considered BACT for a new project, but would be significantly more expensive for IPP. It would be more reasonable to require this new technology for the first time during the early planning stages of a smaller plant.

The staff recommends that an emission limitation based on combustion control using the B & W units be considered BACT for IPP. Although better boiler-burner combinations are available on the market, we do not believe that it is reasonable to incorporate them as a retrofit. The information we have about the B & W units suggests that a limitation ofbetween 0.50 and 0.55 lbs/10^6 BTU / would be appropriate. We suggest that the Committee gather more information at a public hearing about an appropriate limitation for the IPP boilers.

0009Q

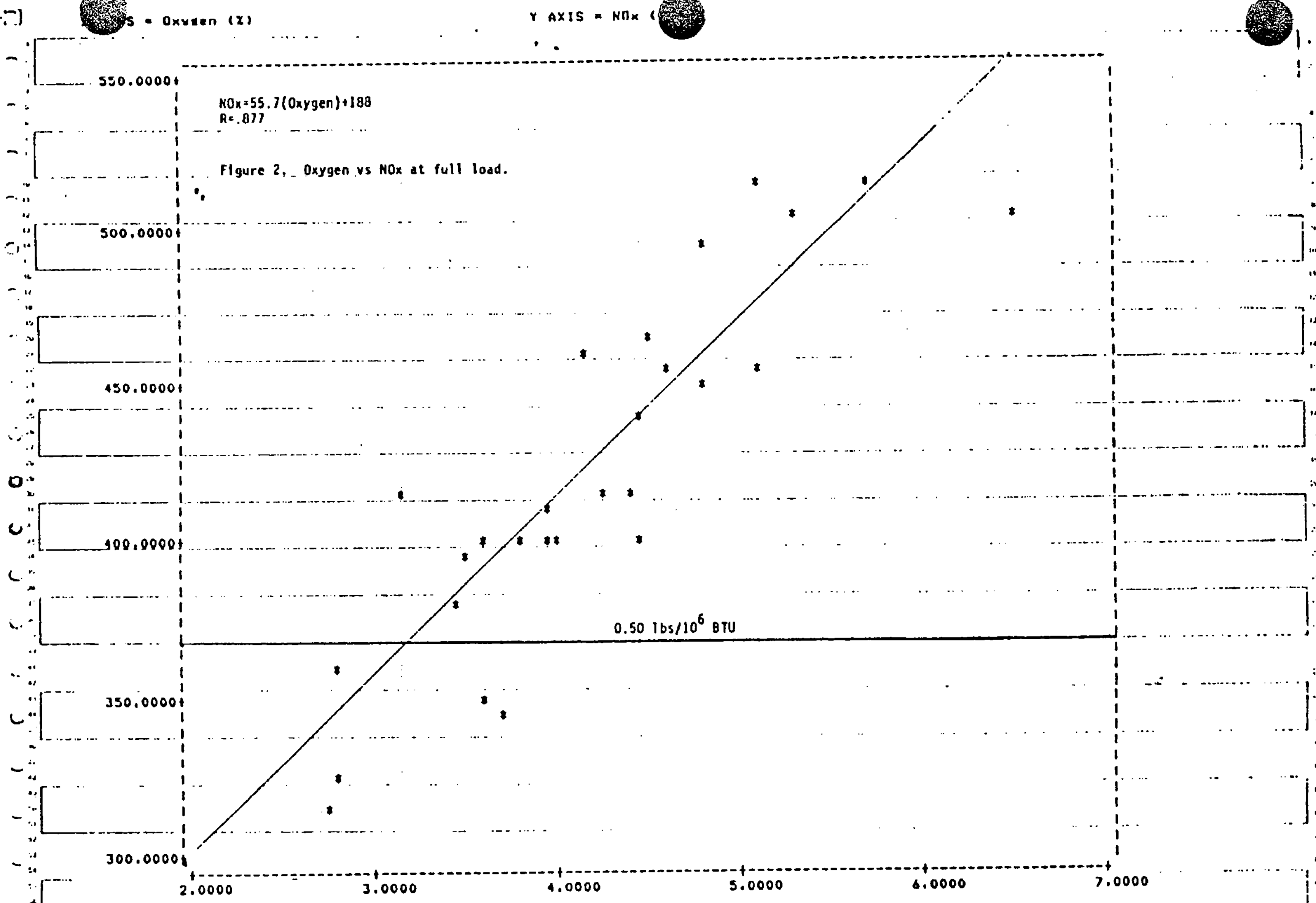

Figure 2,_ Oxygen vs NOx at full load.

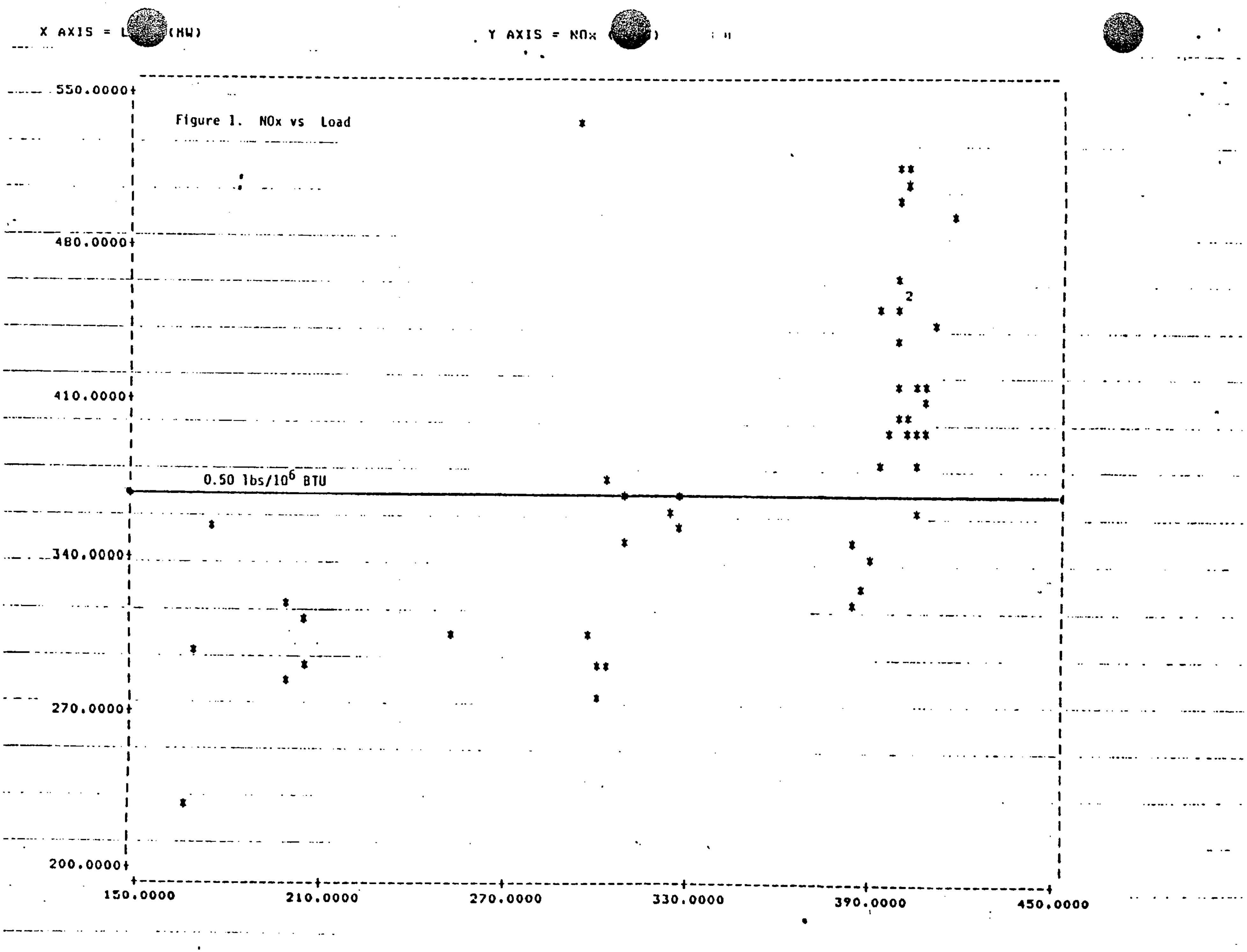

Figure 1. NOx vs Load

V. Recommendations

Approval is recommended with the following conditions:

This air quality approval order authorizes the construction and operation of two coal fired steam electric generating units near Lynndyl in Millard County, with the following conditions:

1. The boilers will be constructed and operated according to the specifications in the contract document number 2010N, as submitted to the Executive Secretary on April 14, 1983.

2. The sulfur dioxide scrubber will be constructed and operated according to the specifications in the contract document number 9255.62.0202, as submitted on April 14, 1983.

3. The fabric filters will be constructed and operated according to the specifications in the contract document number 9255.62.0203, as submitted on April 14, 1983.

4. No boiler unit shall exceed 8.352 X 10^9 BTU/hr heat input rate, as determined by ASTM Method D 3176 and the coal feed rate measured by the plant instrumentation. Records of heat input will be kept for two years and made available to the Executive Secretary on request.

5. No boiler unit shall discharge to the atmosphere:

a. Particulate matter at a rate exceeding
(1) 0.020 lbs/10^6 BTU heat input

b. Sulfur dioxide at a rate exceeding
(1) 0.150 lbs/10^6 BTU heat input
(2) 10.0 percent of the potential combustion concentration

c. Nitrogen oxides at a rate exceeding
(1) lbs/10^6 BTU heat input

d. Visible emissions in excess of 20% opacity

6. The emission limitations in paragraph 5 above will be determined by the following procedures:

a. Particulate matter
40 CFR 60.48a (a (1 - 6))

b. Sulfur dioxide
40 CFR 60.48a (b (1 + 2))
(30 day average)

c. Nitrogen oxides
(1) 40 CFR 60.48a (c)
(30 day average)

d. Opacity - 40 CFR 60, Appendix A, Method 9, and by six minute averages of the output of the continuous emission monitor required by 40 CFR 60.47(a) and Utah Air Conservation Regulations (UACR), Section 4.6.

e. Performance testing shall be completed by the dates required by 40 CFR 60.8a. For the purpose of 40 CFR 60.8a, maximum production rate shall be a boiler heat input of 7.517 X 10^9 BTU/hr and initial startup shall be the first day electricity is produced by the generator. Vaughn

7. Emissions of particulate matter from the following dust collectors shall not exceed a concentration of 0.024 gr/dscf and the following rates: Fowler

A.

1	Railcar unloading (4 units)	15.3	lbs/hr each unit
2	Transfer Building One	7.1	lbs/hr
3	Unit One 13A	6.9	lbs/hr
4	Transfer Building Two	5.5	lbs/hr
5	Transfer Building Four	3.7	lbs/hr
6	Crusher Building One	3.8	lbs/hr
7	Unit One 13B	3.5	lbs/hr
8	Unit Two 14A	4.1	lbs/hr
9	Unit Two 14B	3.5	lbs/hr
10	Limestone Preparation Building	3.5	lbs/hr

B. Stack testing of the dust collectors listed in 7.A.1,2 and 3 above shall be completed within 60 days of startup of each unit. Ducting of gas flow from those dust collectors shall be designed to meet the requirements of 40 CFR 60, Appendix A, Method 1.

C. Stack testing of the dust collectors listed in 7.A.4 through 10 shall be as directed by the Executive Secretary.

D. The test method for the above installations 7.A.1 through 10 shall be 40 CFR 60, Appendix A, Method 5 and 2.

8. Visible emission from the following dust collectors shall not exceed 20% opacity, as determined by 40 CFR 60, Appendix A, Method 9: Fowler

A. Coal Truck Unloading
B. Reserve Reclaim
C. Limestone Truck Unloading Hopper
D. Reclaim Hopper
E. Crusher Building
F. Each of the Dust Collectors Listed in 7.A.1 through 10

9. Fugitive emissions from the following sources shall be minimized as listed herein and visible emissions from these sources shall not exceed 20% opacity, as determined by 40 CFR 60 Appendix A, Method 9: Fowler

A. Coal and limestone conveyor belts - enclosed on three sides.

B. Coal and limestone dumpers - underground receiving.

C. Coal stack out - telescopic spout and wet suppression.

D. Coal and limestone reclaim - underground plow.

E. Coal and limestone storage active pile - residual moisture.

F. Coal and limestone reserve pile - compacting and crusting agent.

G. Limestone stack out - telescopic spout.

H. Flyash silo unloading - mix with scrubber sludge.

I. Coal and limestone haul road - paved.

J. Solid waste area access road - $CaCL_2$ or other dust suppressant treatment.

K. Solid waste haul road - watering.

L. Solid waste/soil stockpile - watering.

M. Solid waste burial pile - compaction and reseeding.

10. Section 4.7, Utah Air Conservation Regulations shall apply only to emissions of particulate, opacity, and nitrogen oxides. Excessive emissions of sulfur dioxide shall be subject to the provisions of 40 CFR 60.46 a (c + d).

11. Reports required by 40 CFR 60.49a shall be submitted to the Executive Secretary by the dates specified in (i) of that part.

12. A quality control program for the continuous monitoring system required by 40 CFR 60.47a and Section 4.6, UACR, must be developed and implemented. As a minimum, the quality control program must have written procedures for each of the following activities:

(1) Installation of CEM's
(2) Calibration of CEM's
(3) Zero and calibration checks and adjustments for CEM's

(4) Preventive maintenance for CEM's (including parts inventory)
(5) Data recording and reporting
(6) Program of corrective action for inoperable CEM's
(7) Annual evaluation of CEM system

The quality control program must be described in detail, suitably documented, and approved by the Executive Secretary prior to the date of performance testing.

13. Post construction monitoring of ambient air for at least one year is required. A quality assurance plan for post construction monitoring must be submitted for approval by the Executive Secretary no later than six months before initial startup of either boiler.

14. All installations and facilities authorized by this approval order shall be maintained in proper condition.

DK:wml
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